Robert J. Humm
Senior Counsel

September 25, 2018

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4872 - 2018 Gas Cost Recovery Filing
Responses to Division Data Requests – Set 2

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] responses to the following data requests in the Division of Public Utilities and Carriers' (Division) Second Set of Data Requests (Division Set 2) in the above-referenced docket: Division 2-3, Division 2-4, Division 2-6, and Division 2-14 through Division 2-17. As agreed with the Division, National Grid will submit its responses to the remaining data requests from Division Set 2 by or before October 2, 2018.

This filing also contains a Motion for Protective Treatment of Confidential Information in accordance with Rule 1.2(g) of the Public Utilities Commission's (PUC) Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). National Grid seeks protection from public disclosure of certain confidential and privileged information, which is contained in its response to Division 2-16. In compliance with Rule 1.2(g), National Grid has provided the PUC with one complete, unredacted copy of the confidential materials in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release,"** and has included redacted copies of the materials for the public filing.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosures
cc: Docket 4872 Service List
Leo Wold, Esq.
Al Mancini, Division
John Bell, Division
Bruce Oliver, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2018	)	Docket No. 4872

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I. Gen. Laws § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

I. BACKGROUND

On September 25, 2018, National Grid submitted responses to the Second Set of Data Requests from the Division of Public Utilities and Carriers in this docket (Division Set 2). Division Set 2 includes Data Request Division 2-16 (seeking measures the Company has taken to control its winter gas supply costs for the 2018-19 winter period). The Company's response to Division 2-16 includes confidential gas cost pricing terms, so the Company has provided redacted and un-redacted versions of its response to Division 2-16.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid).

Therefore, the Company requests that, pursuant to Rule 1.2(g), the PUC afford confidential treatment to the gas cost pricing information contained in the Company's response to Division 2-16.

II. LEGAL STANDARD

Rule 1.2(g) of the PUC's Rules of Practice and Procedure provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1, *et seq*. Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I. Gen. Laws § 38-2-2(4). To the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information as confidential and to protect that information from public disclosure.

In that regard, R.I. Gen. Laws § 38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information would be likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. *Providence Journal Company v. Convention Center Authority*, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. *Providence Journal*, 774 A.2d at 47.

III. BASIS FOR CONFIDENTIALITY

The information contained in the Company's response to Division 2-16 should be protected from public disclosure. The Company's response to Division 2-16 includes confidential gas cost pricing information. The pricing information provided is confidential and privileged information of the type that the Company does not ordinarily make public. Public disclosure of such information could impair the Company's ability to obtain advantageous pricing or other terms in the future, thereby causing substantial competitive harm. Accordingly, the Company is providing its response to Division 2-16 on a voluntary basis to assist the PUC with its decision-making in this proceeding, but respectfully requests that the PUC provide confidential treatment to the information.

IV. CONCLUSION

For the foregoing reasons, National Grid respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

Respectfully submitted,
THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
By its attorney,

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Robert J. Humm, Esq. (#7920)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7415
Dated: September 25, 2018

Division 2-3

Request:

Re: Witness Leary's Attachment AEL-1, page 13 of 16. Please:

a. Explain why the Company shows only 42,671 Dth of Underground Storage in its Design Day Send Out for 2018/19 when Witness Leary's comparable presentation in Docket No. 4719 showed Design Day Underground Storage volumes of 113,860 Dth;

b. Explain why the Company shows Design Day LNG Send Out for 2018/19 of 171,834 Dth when Witness Leary's comparable presentation in Docket No. 4719 showed Design Day LNG Send Out volumes of 69,799 Dth (i.e., an effective year-over-year increase of more than 100,000 Dth or a 146% increase in Design Day LNG requirements;

c. Please provide the economic analyses that the Company relies upon to support a finding that planning for a 146% increase in Design Day LNG Send Out is more cost-effective than other alternatives (e.g., greater use of underground Storage.

Response:

a. The Storage and Peaking values shown in the Design Day Sendout in Attachment AEL-1, Page 12 of Docket No. 4719 filed on September 1, 2017 were incorrect. On September 29, 2017, the Company provided an updated Design Day Sendout in its Supplemental Gas Cost Recovery filing in Docket No. 4719. In that filing, the Company restated the Design Day Sendout as follows:

	AEL-1, Page 12 Design Day Send Out
Pipeline	174,349 Dth
Storage	42,694 Dth
Peaking	140,965 Dth
Total	358,008 Dth

Therefore, the underground storage requirement for the 2018/19 Design Day was approximately the same as the requirements for the 2017/2018 Design Day.

Division 2-3, page 2

b. Please see the above response to part (a). The liquefied natural gas (LNG) sendout for the 2018/19 Design Day is 30,869 Dth, or 22 percent higher than the restated 2017/18 Design Day.

c. Please see the above response to part (a). The Company's 2018/19 LNG Design Day sendout is only 22 percent (not 146 percent) greater than the prior year, so additional economic analysis was not warranted.

Prepared by or under the supervision of: Ann E. Leary and Nancy G. Culliford

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Division 2-4

Request:

Re: Witness Leary's Attachment AEL-1, page 15 of 16. Please:

a. Provide the workpapers, data, analyses, and assumptions relied upon to compute the "**Normal** Billing DD" for each month in the period November 2018 through October 2019;

b. Provide the workpapers, data, analyses, and assumptions relied upon to compute the "**Normal** Billing DD" for each month in the period November 2017 through October 2018 presented in Attachment AEL-1 page 14 of 15, in Docket No. 4719;

c. Provide the workpapers, data, analyses, and assumptions relied upon to compute the "**Design** Billing DD" for each month in the period November 2018 through October 2019;

d. Provide the workpapers, data, analyses, and assumptions relied upon to compute the "**Design** Billing DD" for each month in the period November 2017 through October 2018 presented in Attachment AEL-1 page 14 of 15, in Docket No. 4719;

e. Provide the Company's **Actual** Billing Degree Days for each month of its current GCR year to date and for each of the five immediately preceding GCR years (i.e., Nov – Oct).

Response:

a. Please see the attached Excel file, Attachment DIV 2-4 (a)-(e), which shows the derivation of the normal monthly billing degree days for the period November 2018 through October 2019. The normal monthly billing degrees days are computed by averaging the normal degree days for each cycle within each billing month, using the normal daily degree days approved in Docket No. 4323. Please note in preparing this response, the Company determined it has used the incorrect normal daily degree days to derive the normal monthly billing degree days. The annual normal billing degree days in Attachment AEL-1, Page 15, Line (52) should have been 5,433 instead of 5,467. This revision, however, has no impact on the overall proposed November 1, 2018 Gas Cost Recovery (GCR) factors of $0.6100 per therm for High Load Factor customers and $0.7041 per therm for Low Load Factor customers. For illustrative purposes, the Company has included Attachment DIV 2-4 (f), which details the calculation of the proposed November 1, 2018 GCR factors utilizing the revised normal billing degree days referenced above.

b. Please see the attached Excel file, Attachment DIV 2-4 (a)-(e), which shows the derivation of the normal monthly degree days for the period November 2017 through October 2018, as shown in Attachment AEL-1, Page 15, Line (52) in Docket No. 4719. Please note that although this attachment was labeled normal billing degree days, it was actually normal calendar degree days. The normal calendar degree days were approved in Docket No. 4323. Also, the purpose of Attachment AEL-1, Pages 12-15 in Docket No. 4719 is to determine the monthly sales under design weather conditions, which is then used to allocate the fixed gas costs between the High Load Factor and Low Load Factor rate classes. The Company calculates the monthly design sales by adjusting the heating portion of the normal monthly forecast by the ratio of the normal monthly degrees day compared to design monthly degree days. In last year's analysis in Docket No. 4719, the Company used both calendar normal and calendar design monthly degree days. This year, the Company further refined this calculation by using both the normal and design monthly billing degree days instead of calendar monthly degree days in this year's calculation to more closely align with the billing forecast.

c. Please see the attached Excel file, Attachment DIV 2-4 (a)-(e), which shows the derivation of the design monthly billing degree days for the period November 2018 through October 2019, as shown in Attachment AEL-1, Page 15, Line (52).

d. Please see the attached Excel file, Attachment DIV 2-4 (a)-(e), which shows the derivation of the design monthly degree days for the period November 2017 through October 2018, as shown in Attachment AEL-1, Page 15, Line (52) in Docket No. 4719. As indicated in response to part (b) above, although this attachment was labeled design billing degree days, it was actually design calendar degree days.

e. Please see the attached Excel file, Attachment DIV 2-4 (a)-(e), for the Company's actual billing degree days for each month of its current GCR year to date and for each of the five immediately preceding GCR years.

The Narragansett Electric Company
d/b/a National Grid
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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2018

	Description (a)	Source: Reference (b)	Source: Line # (c)	High Load[1] (d)	Low Load[2] (e)	FT-2 Mkter[3] (f)
(1)	Fixed Cost Factor - $/dktherm	AEL-1, pg 2	Line (18)	$2.1492	$3.0728	
(2)	Variable Cost Factor -$/dktherm	AEL-1, pg 3	Line (13)	$3.8346	$3.8346	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$5.9838	$6.9074	
(4)	Uncollectible %	Docket 4770		1.91%	1.91%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$6.1003	$7.0419	
(6)	GCR Charge on a per therm basis	(5) ÷ 10		**$0.6100**	**$0.7041**	
(7)	Current rate effective 09/01/18* - $/therm			$0.7090	$0.7516	
(8)	Increase / (Decrease) - $/therm	(6) - (7)		($0.0990)	($0.0475)	
(9)	Percent Decrease	(8) ÷ (7)		-14.0%	-6.3%	

* Docket No.4770, Revised Compliance Attachment 18

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load

[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load

[3] See AEL-5 for calculation of FT-2 rate

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Fixed Cost Calculation ($ per Dth)

	Description	Source: Reference	Source: Line #	Amount	High Load Factor Total	Low Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Costs (net of Cap Rel to marketers)	AEL-1, pg 5	Line (63)	$81,074,626		
	Less:					
(2)	NGPMP Customer Benefit	NGC-EDA-1		($4,000,000)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	AEL-5, pg 2	Line (25)	($4,448,149)		
(5)	System Pressure to DAC			$0		
(6)	Refunds			$0		
(7)	Total Credits	Sum[(2):(6)]		($8,448,149)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4770	Compliance Attachment 2 Schedule 32 Pg 5	$829,823		
(9)	Portable LNG Storage Cost			$0		
(10)	Working Capital Requirement	AEL-1, pg 9	Line (16)	$614,767		
(11)	Deferred Fixed Cost Under-recovered	AEL-1, pg 7	Line (17)	$7,218,742		
(12)	Reconciliation Amount from Fixed costs- Marketers	AEL-7, pg 2	Line (50)	$24,654		
(13)	Total Additions	Sum[(8):(12)]		$8,687,986		
(14)	Total Fixed Costs	(1) + (7) + (13)		$81,314,463		
(15)	Design Winter Sales Percentage	AEL-1, pg 13	Lines (10) & (11)		1.70%	98.30%
(16)	Allocated Supply Fixed Costs	(14) x (15)			$1,378,774	$79,935,688
(17)	Sales (Dth) Nov 2018 - Oct 2019	AEL-1, pg 12	Line (9)	26,654,839	641,511	26,013,328
(18)	Fixed Factor	(16) ÷ (17)			**$2.1492**	**$3.0728**

(17) Col (e): AEL-1 page 12, Sum[Lines (1), (6), (8)]
Col (f): AEL-1 page 12, Sum[Lines (2):(5), (7)]

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Design Winter Period and Design Day Throughput (Dth)

	Rate Class (a)	Reference	Line #	Nov-18 (b)	Dec-18 (c)	Jan-19 (d)	Feb-19 (e)	Mar-19 (f)	Total (g)	% (h)
	SALES (dth)									
(1)	Residential Non-Heating	AEL-1, pg 16	Line (70)	22,956	37,954	52,300	44,260	40,909	198,378	0.96%
(2)	Residential Heating	AEL-1, pg 16	Line (71)	1,381,517	2,644,811	3,924,281	4,118,931	3,405,894	15,475,435	74.55%
(3)	Small C&I	AEL-1, pg 16	Line (72)	135,815	324,961	521,536	514,173	425,448	1,921,933	9.26%
(4)	Medium C&I	AEL-1, pg 16	Line (74)	213,828	429,991	690,273	588,911	490,020	2,413,023	11.62%
(5)	Large LLF	AEL-1, pg 16	Line (76)	48,579	102,442	137,376	147,497	128,040	563,934	2.72%
(6)	Large HLF	AEL-1, pg 16	Line (78)	20,424	24,288	34,362	29,689	24,433	133,196	0.64%
(7)	Extra Large LLF	AEL-1, pg 16	Line (80)	2,836	6,610	6,637	8,748	7,173	32,005	0.15%
(8)	Extra Large HLF	AEL-1, pg 16	Line (82)	10,139	4,484	0	4,654	1,128	20,405	0.10%
(9)	Total Sales	Sum[(1):(8)]		1,836,094	3,575,541	5,366,766	5,456,863	4,523,045	20,758,310	100.00%
(10)	Low Load Factor	Sum[(2):(5),(7)]		1,782,576	3,508,815	5,280,104	5,378,260	4,456,575	20,406,331	98.30%
(11)	High Load Factor	Sum[(1),(6),(8)]		53,519	66,726	86,662	78,603	66,470	351,979	1.70%

2018/2019 Design Day Send Out

(12)	Pipeline	175,722	Dktherm
(13)	Underground Storage	42,671	Dktherm
(14)	LNG	171,834	Dktherm
(15)	Total Projected 2018/2019 Design Day	390,227	Dktherm

(1) Column (h): [Line (1), Col (g)]÷[Line (9), Col (g)]
(2) Column (h): [Line (2), Col (g)]÷[Line (9), Col (g)]
(3) Column (h): [Line (3), Col (g)]÷[Line (9), Col (g)]
(4) Column (h): [Line (4), Col (g)]÷[Line (9), Col (g)]
(5) Column (h): [Line (5), Col (g)]÷[Line (9), Col (g)]
(6) Column (h): [Line (6), Col (g)]÷[Line (9), Col (g)]
(7) Column (h): [Line (7), Col (g)]÷[Line (9), Col (g)]
(8) Column (h): [Line (8), Col (g)]÷[Line (9), Col (g)]
(10) Column (h): [Line (10), Col (g)]÷[Line (9), Col (g)]
(11) Column (h): [Line (11), Col (g)]÷[Line (9), Col (g)]

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4872
Attachment DIV 2-4 (f)
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Derivation of Monthly Design Sales

Normal Volumes (Dth)

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(1)	Residential Non-Heating	22,227	35,614	47,291	40,666	38,648	37,807	26,709	21,502	16,823	16,284	17,571	16,077	337,218
(2)	Residential Heating	1,271,942	2,396,453	3,427,224	3,653,832	3,123,499	2,122,108	1,225,830	619,954	435,361	397,039	439,559	532,719	19,645,520
(3)	Small C&I	125,069	293,293	453,403	454,861	389,113	258,015	116,773	65,276	40,925	36,380	48,446	52,987	2,334,542
(4)	Small Transport	12,566	20,010	25,711	27,397	23,943	17,207	11,753	5,273	2,876	2,532	2,898	6,015	158,180
(5)	Medium C&I	200,308	392,753	606,014	526,512	452,808	383,665	197,339	125,789	98,066	94,334	97,543	110,966	3,286,097
(6)	Med Transport	173,197	315,865	411,364	369,590	342,996	260,713	155,362	95,839	75,553	73,024	76,357	92,379	2,442,238
(7)	Large Low Load	44,361	92,278	119,512	130,436	117,009	85,027	49,006	18,991	11,143	9,807	13,893	16,841	708,304
(8)	Large Low Load- Transport	176,854	296,272	358,609	352,261	309,727	189,270	115,275	50,934	34,456	32,191	43,742	83,995	2,043,586
(9)	Large High Load	19,715	23,207	31,558	27,637	23,504	22,820	19,033	15,521	13,976	13,402	16,077	16,190	242,642
(10)	Large High Load- Transport	72,228	99,002	112,191	98,705	100,840	78,821	67,676	59,185	50,762	58,565	58,743	59,808	916,525
(11)	XL Low Load	2,541	5,897	5,728	7,685	6,516	3,854	3,652	1,426	342	84	293	847	38,865
(12)	XL Low Load-Transport	122,430	178,864	194,162	182,450	157,144	96,228	62,805	27,050	21,711	20,914	29,069	80,905	1,173,733
(13)	XL High Load	9,650	4,484	0	4,654	1,128	0	8,824	6,431	5,706	6,321	5,860	8,592	61,651
(14)	XL High Load-Transport	561,571	629,875	608,190	524,520	597,555	475,819	466,687	479,539	493,717	517,144	445,471	497,844	6,297,932
(15)	**Total**	2,814,661	4,783,867	6,400,956	6,401,206	5,684,431	4,031,353	2,526,723	1,592,708	1,301,416	1,278,022	1,295,522	1,576,166	39,687,032
(16)	HLF	685,392	792,183	799,231	696,182	761,675	615,266	588,928	582,177	580,984	611,716	543,721	598,511	7,855,967
(17)	LLF	2,129,269	3,991,684	5,601,726	5,705,024	4,922,756	3,416,087	1,937,794	1,010,531	720,432	666,306	751,801	977,655	31,831,064

Baseload

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
		30	31	31	28	31	30	31	30	31	31	30	31	
(18)	Residential Non-Heating	16,525	17,076	17,076	15,424	17,076	16,525	17,076	16,525	16,823	16,284	16,525	16,077	199,012
(19)	Residential Heating	414,769	428,595	428,595	387,118	428,595	414,769	428,595	414,769	428,595	397,039	414,769	428,595	5,014,803
(20)	Small C&I	41,006	42,373	42,373	38,272	42,373	41,006	42,373	41,006	40,925	36,380	41,006	42,373	491,463
(21)	Small Transport	2,709	2,799	2,799	2,528	2,799	2,709	2,799	2,709	2,799	2,532	2,709	2,799	32,687
(22)	Medium C&I	94,546	97,698	97,698	88,243	97,698	94,546	97,698	94,546	97,698	94,334	94,546	97,698	1,146,950
(23)	Med Transport	73,348	75,793	75,793	68,458	75,793	73,348	75,793	73,348	75,553	73,024	73,348	75,793	889,394
(24)	Large Low Load	11,362	11,741	11,741	10,604	11,741	11,362	11,741	11,362	11,143	9,807	11,362	11,741	135,705
(25)	Large Low Load- Transport	35,997	37,196	37,196	33,597	37,196	35,997	37,196	35,997	34,456	32,191	35,997	37,196	430,213
(26)	Large High Load	14,170	14,643	14,643	13,226	14,643	14,170	14,643	14,170	13,976	13,402	14,170	14,643	170,498
(27)	Large High Load- Transport	54,805	56,632	56,632	51,152	56,632	54,805	56,632	54,805	50,762	56,632	54,805	56,632	660,927
(28)	XL Low Load	235	242	242	219	242	235	242	235	242	84	235	242	2,697
(29)	XL Low Load-Transport	23,378	24,158	24,158	21,820	24,158	23,378	24,158	23,378	21,711	20,914	23,378	24,158	278,747
(30)	XL High Load	5,833	4,484	0	4,654	1,128	0	6,027	5,833	5,706	6,027	5,833	6,027	51,552
(31)	XL High Load-Transport	474,891	490,721	490,721	443,231	490,721	474,891	466,687	474,891	490,721	490,721	445,471	490,721	5,724,385
(32)	Total	1,263,574	1,304,150	1,299,666	1,178,546	1,300,794	1,257,741	1,281,659	1,263,574	1,291,109	1,249,372	1,234,154	1,304,694	15,229,034
(33)	HLF	566,224	583,556	579,071	527,686	580,199	560,392	561,065	566,224	577,987	583,066	536,804	584,100	6,806,375
(34)	LLF	697,350	720,595	720,595	650,860	720,595	697,350	720,595	697,350	713,122	666,306	697,350	720,595	8,422,659

The Narragansett Electric Company
d/b/a National Grid
Docket No. 4872
Attachment DIV 2-4 (f)
Page 5 of 6

Derivation of Monthly Design Sales

Heat Volumes

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(35)	Residential Non-Heating	5,702	18,538	30,215	25,242	21,572	21,282	9,633	4,976	0	0	1,046	0	138,206
(36)	Residential Heating	857,173	1,967,859	2,998,629	3,266,714	2,694,904	1,707,339	797,236	205,185	6,766	0	24,790	104,124	14,630,717
(37)	Small C&I	84,063	250,920	411,030	416,589	346,741	217,010	74,401	24,270	0	0	7,440	10,614	1,843,079
(38)	Small Transport	9,858	17,211	22,912	24,869	21,144	14,498	8,954	2,564	77	0	190	3,216	125,493
(39)	Medium C&I	105,762	295,055	508,316	438,269	355,110	289,118	99,641	31,243	368	0	2,996	13,268	2,139,147
(40)	Med Transport	99,849	240,072	335,571	301,131	267,203	187,364	79,569	22,491	0	0	3,009	16,585	1,552,844
(41)	Large Low Load	32,999	80,537	107,771	119,831	105,269	73,666	37,265	7,629	0	0	2,531	5,101	572,599
(42)	Large Low Load- Transport	140,857	259,075	321,412	318,665	272,531	153,274	78,078	14,938	0	0	7,745	46,799	1,613,373
(43)	Large High Load	5,545	8,565	16,915	14,412	8,862	8,650	4,391	1,351	0	0	1,906	1,547	72,144
(44)	Large High Load- Transport	17,423	42,370	55,559	47,553	44,208	24,015	11,043	4,379	0	1,933	3,938	3,176	255,597
(45)	XL Low Load	2,307	5,654	5,486	7,466	6,273	3,619	3,409	1,191	99	0	59	605	36,168
(46)	XL Low Load-Transport	99,052	154,707	170,004	160,630	132,986	72,850	38,647	3,671	0	0	5,691	56,748	894,986
(47)	XL High Load	3,818	0	0	0	0	0	2,797	598	0	294	27	2,565	10,099
(48)	XL High Load-Transport	86,681	139,154	117,470	81,289	106,834	928	0	4,648	2,997	26,424	0	7,123	573,547
(49)	Total	1,551,087	3,479,716	5,101,290	5,222,660	4,383,637	2,773,612	1,245,063	329,135	10,307	28,650	61,368	271,471	24,457,998
(50)	HLF	119,168	208,627	220,160	168,496	181,476	54,875	27,864	15,953	2,997	28,650	6,917	14,411	1,049,593
(51)	LLF	1,431,919	3,271,089	4,881,131	5,054,164	4,202,161	2,718,738	1,217,200	313,181	7,310	0	54,451	257,060	23,408,405
(52)	**Normal Billing DD**	**441**	**756**	**995**	**1038**	**909**	**640**	**351**	**126**	**15**	**0**	**17**	**145**	**5433**

Heat Factors

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(53)	Residential Non-Heating	13	25	30	24	24	33	27	39	0	0	62	0	25
(54)	Residential Heating	1,943	2,603	3,015	3,148	2,963	2,669	2,269	1,624	460	0	1,476	720	2,693
(55)	Small C&I	191	332	413	401	381	339	212	192	0	0	443	73	339
(56)	Small Transport	22	23	23	24	23	23	25	20	5	0	11	22	23
(57)	Medium C&I	240	390	511	422	390	452	284	247	25	0	178	92	394
(58)	Med Transport	226	318	337	290	294	293	226	178	0	0	179	115	286
(59)	Large Low Load	75	107	108	115	116	115	106	60	0	0	151	35	105
(60)	Large Low Load- Transport	319	343	323	307	300	240	222	118	0	0	461	324	297
(61)	Large High Load	13	11	17	14	10	14	12	11	0	0	113	11	13
(62)	Large High Load- Transport	39	56	56	46	49	38	31	35	0	7,730	234	22	47
(63)	XL Low Load	5	7	6	7	7	6	10	9	7	0	3	4	7
(64)	XL Low Load-Transport	225	205	171	155	146	114	110	29	0	0	339	392	165
(65)	XL High Load	9	0	0	0	0	0	8	5	0	1,176	2	18	2
(66)	XL High Load-Transport	196	184	118	78	117	1	0	37	204	105,694	0	49	106
(67)	Total	3,516	4,603	5,130	5,033	4,820	4,336	3,544	2,605	701	114,600	3,653	1,877	4,502
(68)	**NormalBilling DD**	**441**	**756**	**995**	**1038**	**909**	**640**	**351**	**126**	**15**	**0**	**17**	**145**	**5433**
(69)	**DesignBilling DD**	**498**	**851**	**1159**	**1186**	**1005**	**758**	**359**	**157**	**19**	**3**	**27**	**209**	**6231**

Derivation of Monthly Design Sales

Design Sales

		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(70)	Residential Non-Heating	22,956	37,954	52,300	44,260	40,909	41,759	26,929	22,691	16,823	16,284	18,230	16,077	357,172
(71)	Residential Heating	1,381,517	2,644,811	3,924,281	4,118,931	3,405,894	2,439,206	1,244,099	668,997	428,595	397,039	455,200	578,716	21,687,288
(72)	Small C&I	135,815	324,961	521,536	514,173	425,448	298,320	118,478	71,077	40,925	36,380	53,141	57,676	2,597,929
(73)	Small Transport	13,826	22,182	29,508	30,938	26,158	19,899	11,958	5,885	2,799	2,532	3,018	7,435	176,140
(74)	Medium C&I	213,828	429,991	690,273	588,911	490,020	437,362	199,622	133,257	97,698	94,334	99,433	116,828	3,591,557
(75)	Med Transport	185,961	346,164	466,989	412,463	370,996	295,511	157,185	101,214	75,553	73,024	78,256	99,705	2,663,022
(76)	Large Low Load	48,579	102,442	137,376	147,497	128,040	98,709	49,860	20,815	11,143	9,807	15,489	19,095	788,853
(77)	Large Low Load- Transport	194,860	328,969	411,886	397,631	338,285	217,737	117,064	54,504	34,456	32,191	48,629	104,669	2,280,882
(78)	Large High Load	20,424	24,288	34,362	29,689	24,433	24,427	19,134	15,844	13,976	13,402	17,279	16,873	254,132
(79)	Large High Load- Transport	74,456	104,349	121,401	105,475	105,472	83,281	67,929	60,231	50,762	56,632	61,228	61,211	952,427
(80)	XL Low Load	2,836	6,610	6,637	8,748	7,173	4,526	3,730	1,711	242	84	330	1,114	43,743
(81)	XL Low Load-Transport	135,093	198,389	222,342	205,320	171,079	109,758	63,690	27,927	21,711	20,914	32,660	105,974	1,314,858
(82)	XL High Load	10,139	4,484	0	4,654	1,128	0	8,888	6,574	5,706	6,027	5,877	9,726	63,202
(83)	XL High Load-Transport	572,652	647,437	627,662	536,093	608,750	475,991	466,687	480,650	490,721	490,721	445,471	500,991	6,343,825
(84)	Total	3,012,942	5,223,032	7,246,555	7,144,784	6,143,787	4,546,487	2,555,253	1,671,378	1,291,109	1,249,372	1,334,242	1,696,090	43,115,030
(85)	HLF	700,626	818,513	835,725	720,172	780,692	625,458	589,567	585,991	577,987	583,066	548,086	604,877	7,970,759
(86)	LLF	2,312,316	4,404,519	6,410,830	6,424,612	5,363,095	3,921,029	1,965,686	1,085,387	713,122	666,306	786,157	1,091,213	35,144,271

Source: Attachement TEP-1

Division 2-6

Request:

Re: Witness Leary's Attachment AEL-4, pages 1 of 5 through 5 of 5, please:

a. Verify that the bill comparisons are based on comparing bills computed at the Company's current GCR rates which became effective in March 2018 with the Company's proposed GCR charges in this proceeding;

b. Provide bill comparisons for each rate class shown in Attachment AEL-4 which reflect the charges that customers can expect to pay during the upcoming months of November 2018 through February 2019 (using the Company's proposed GCR charges in this proceeding, the proposed DAC charges in Docket No. 4846, the Base Rates recently approved by the Commission in Docket No. 4770) and the charges actually applied to usage for customers in each rate class during the months of November 2017 through February 2018 given the GCR charges, DAC charges, and Base Rates that were in effect for those months.

Response:

a. The bill comparisons are based on comparing bills computed at the Company's current Gas Cost Recovery (GCR) factors, which became effective in March 2018 and were further adjusted as of September 1, 2018 to reflect the change in the uncollectible percentage pursuant to Docket No. 4770, with bills computed at the GCR factors proposed in this proceeding, with all other rates remaining unchanged.

b. Please see Attachment DIV 2-6 (b), which presents the bill comparison typically provided by the Company and which compares bills based on all rates and factors in effect during November 2017 through February 2018 (column (c)) and bills based on all rates and factors assumed to be in effect during the upcoming months of November 2018 through February 2019, both proposed for November 1, 2018 (proposed GCR factors in this proceeding and proposed DAC factors in Docket No. 4846) and approved (base distribution rates from Docket No. 4770) (column (b)).

Prepared by or under the supervision of: Ann E. Leary

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

							Difference due to:						
(1)		Nov-Feb ONLY	Proposed	Current									
(2)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		296	$463.32	$431.32	$32.00	7.4%	$29.52	$51.79	($13.61)	($36.14)	($0.52)	$0.00	$0.96
(8)		328	$506.81	$471.80	$35.01	7.4%	$32.27	$57.40	($15.10)	($40.05)	($0.56)	$0.00	$1.05
(9)		361	$551.67	$513.55	$38.12	7.4%	$35.12	$63.17	($16.60)	($44.08)	($0.63)	$0.00	$1.14
(10)		392	$593.78	$551.02	$42.76	7.8%	$39.45	$68.59	($18.03)	($47.86)	($0.68)	$0.00	$1.28
(11)		424	$637.29	$588.28	$49.01	8.3%	$45.37	$74.21	($19.51)	($51.78)	($0.75)	$0.00	$1.47
(12)	**Average Customer**	**456**	**$680.75**	**$625.13**	**$55.63**	**8.9%**	$51.62	$79.80	($20.98)	($55.67)	($0.81)	$0.00	$1.67
(13)		488	$724.25	$662.00	$62.24	9.4%	$57.87	$85.41	($22.46)	($59.58)	($0.86)	$0.00	$1.87
(14)		520	$767.74	$698.88	$68.86	9.9%	$64.11	$91.00	($23.92)	($63.49)	($0.91)	$0.00	$2.07
(15)		551	$809.86	$734.48	$75.38	10.3%	$70.28	$96.43	($25.35)	($67.28)	($0.96)	$0.00	$2.26
(16)		584	$854.71	$771.59	$83.11	10.8%	$77.61	$102.19	($26.86)	($71.30)	($1.02)	$0.00	$2.49
(17)		616	$898.21	$807.27	$90.94	11.3%	$85.02	$107.80	($28.32)	($75.22)	($1.07)	$0.00	$2.73

Residential Heating Low Income:

							Difference due to:							
(18)		Nov-Feb ONLY	Proposed	Current										
(19)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	Total Bill	GCR	DAC		EE	LIHEAP	GET
(20)								Discount		Base DAC	ISR			
(21)			-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
(22)		296	$344.28	$411.71	($67.43)	-16.4%	$48.54	($111.32)	$51.79	($17.76)	($36.14)	($0.52)	$0.00	($2.02)
(23)		328	$376.57	$450.64	($74.08)	-16.4%	$52.79	($121.76)	$57.40	($19.68)	($40.05)	($0.56)	$0.00	($2.22)
(24)		361	$409.84	$490.80	($80.97)	-16.5%	$57.18	($132.51)	$63.17	($21.66)	($44.08)	($0.63)	$0.00	($2.43)
(25)		392	$441.09	$526.96	($85.87)	-16.3%	$62.79	($142.62)	$68.59	($23.52)	($47.86)	($0.68)	$0.00	($2.58)
(26)		424	$473.37	$563.00	($89.63)	-15.9%	$69.89	($153.06)	$74.21	($25.45)	($51.78)	($0.75)	$0.00	($2.69)
(27)	**Average Customer**	**456**	**$505.63**	**$598.67**	**($93.04)**	**-15.5%**	$77.28	($163.49)	$79.80	($27.36)	($55.67)	($0.81)	$0.00	($2.79)
(28)		488	$537.91	$634.36	($96.45)	-15.2%	$84.68	($173.92)	$85.41	($29.28)	($59.58)	($0.86)	$0.00	($2.89)
(29)		520	$570.18	$670.06	($99.88)	-14.9%	$92.07	($184.36)	$91.00	($31.20)	($63.49)	($0.91)	$0.00	($3.00)
(30)		551	$601.43	$704.53	($103.09)	-14.6%	$99.33	($194.46)	$96.43	($33.06)	($67.28)	($0.96)	$0.00	($3.09)
(31)		584	$634.71	$740.51	($105.81)	-14.3%	$107.76	($205.22)	$102.19	($35.04)	($71.30)	($1.02)	$0.00	($3.17)
(32)		616	$666.98	$775.13	($108.15)	-14.0%	$116.20	($215.66)	$107.80	($36.96)	($75.22)	($1.07)	$0.00	($3.24)

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4872
Attachment DIV 2-6 (b)
Page 1 of 5

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:

Residential Non-Heating:

							Difference due to:						
(1)		Nov-Feb ONLY	Proposed	Current									
(2)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)			-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		59	$134.58	$133.04	$1.54	1.2%	$10.31	$7.32	($4.78)	($11.25)	($0.11)	$0.00	$0.05
(8)		65	$142.04	$140.77	$1.26	0.9%	$10.96	$8.08	($5.27)	($12.41)	($0.13)	$0.00	$0.04
(9)		71	$149.52	$148.52	$1.01	0.7%	$11.60	$8.82	($5.76)	($13.55)	($0.13)	$0.00	$0.03
(10)		77	$156.99	$156.28	$0.71	0.5%	$12.24	$9.55	($6.26)	($14.70)	($0.14)	$0.00	$0.02
(11)		83	$164.48	$163.99	$0.49	0.3%	$12.88	$10.30	($6.72)	($15.84)	($0.15)	$0.00	$0.01
(12)	**Average Customer**	**90**	**$173.19**	**$173.02**	**$0.16**	**0.1%**	$13.63	$11.17	($7.31)	($17.17)	($0.16)	$0.00	$0.00
(13)		97	$181.91	$182.04	($0.12)	-0.1%	$14.38	$12.04	($7.86)	($18.50)	($0.18)	$0.00	($0.00)
(14)		103	$189.39	$189.78	($0.39)	-0.2%	$15.02	$12.78	($8.35)	($19.64)	($0.19)	$0.00	($0.01)
(15)		109	$196.87	$197.53	($0.67)	-0.3%	$15.66	$13.53	($8.84)	($20.79)	($0.21)	$0.00	($0.02)
(16)		115	$204.32	$205.29	($0.96)	-0.5%	$16.31	$14.27	($9.33)	($21.95)	($0.23)	$0.00	($0.03)
(17)		121	$211.80	$213.01	($1.21)	-0.6%	$16.95	$15.01	($9.81)	($23.09)	($0.23)	$0.00	($0.04)

Residential Non-Heating Low Income:

							Difference due to:							
(18)		Nov-Feb ONLY	Proposed	Current										
(19)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	Total Bill	GCR	DAC		EE	LIHEAP	GET
(20)								Discount		Base DAC	ISR			
(21)			-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------	-------------
(22)		59	$100.28	$125.01	($24.72)	-19.8%	$18.10	($32.43)	$7.32	($5.62)	($11.25)	($0.11)	$0.00	($0.74)
(23)		65	$105.83	$132.47	($26.64)	-20.1%	$19.01	($34.22)	$8.08	($6.17)	($12.41)	($0.13)	$0.00	($0.80)
(24)		71	$111.37	$139.94	($28.57)	-20.4%	$19.91	($36.01)	$8.82	($6.76)	($13.55)	($0.13)	$0.00	($0.86)
(25)		77	$116.92	$147.43	($30.51)	-20.7%	$20.82	($37.81)	$9.55	($7.32)	($14.70)	($0.14)	$0.00	($0.92)
(26)		83	$122.45	$154.88	($32.42)	-20.9%	$21.72	($39.59)	$10.30	($7.89)	($15.84)	($0.15)	$0.00	($0.97)
(27)	**Average Customer**	**90**	**$128.93**	**$163.59**	**($34.66)**	**-21.2%**	$22.78	($41.69)	$11.17	($8.56)	($17.17)	($0.16)	$0.00	($1.04)
(28)		97	$135.38	$172.28	($36.90)	-21.4%	$23.84	($43.77)	$12.04	($9.22)	($18.50)	($0.18)	$0.00	($1.11)
(29)		103	$140.92	$179.76	($38.84)	-21.6%	$24.74	($45.56)	$12.78	($9.80)	($19.64)	($0.19)	$0.00	($1.17)
(30)		109	$146.46	$187.24	($40.78)	-21.8%	$25.65	($47.36)	$13.53	($10.38)	($20.79)	($0.21)	$0.00	($1.22)
(31)		115	$152.00	$194.72	($42.72)	-21.9%	$26.55	($49.15)	$14.27	($10.94)	($21.95)	($0.23)	$0.00	($1.28)
(32)		121	$157.54	$202.17	($44.63)	-22.1%	$27.46	($50.94)	$15.01	($11.50)	($23.09)	($0.23)	$0.00	($1.34)

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4872
Attachment DIV 2-6 (b)
Page 2 of 5

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:

C & I Small:

							Difference due to:						
(1)		Nov-Feb ONLY	Proposed	Current									
(2)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		456	$680.82	$696.64	($15.82)	-2.3%	($3.88)	$79.81	($29.52)	($60.51)	($1.25)	$0.00	($0.47)
(8)		503	$740.01	$749.33	($9.32)	-1.2%	$3.60	$88.03	($32.55)	($66.75)	($1.38)	$0.00	($0.28)
(9)		553	$802.99	$805.73	($2.75)	-0.3%	$11.23	$96.77	($35.78)	($73.38)	($1.51)	$0.00	($0.08)
(10)		602	$864.71	$858.83	$5.88	0.7%	$20.83	$105.36	($38.95)	($79.89)	($1.65)	$0.00	$0.18
(11)		651	$926.44	$910.29	$16.15	1.8%	$32.03	$113.94	($42.12)	($86.39)	($1.79)	$0.00	$0.48
(12)	**Average Customer**	**700**	**$988.14**	**$961.73**	**$26.41**	**2.7%**	$43.22	$122.50	($45.29)	($92.89)	($1.92)	$0.00	$0.79
(13)		749	$1,049.88	$1,013.19	$36.69	3.6%	$54.42	$131.09	($48.48)	($99.39)	($2.05)	$0.00	$1.10
(14)		798	$1,111.60	$1,064.64	$46.96	4.4%	$65.61	$139.65	($51.64)	($105.89)	($2.18)	$0.00	$1.41
(15)		847	$1,173.31	$1,116.06	$57.25	5.1%	$76.81	$148.23	($54.81)	($112.39)	($2.30)	$0.00	$1.72
(16)		897	$1,236.27	$1,168.55	$67.72	5.8%	$88.26	$156.97	($58.04)	($119.04)	($2.46)	$0.00	$2.03
(17)		945	$1,296.74	$1,218.97	$77.77	6.4%	$99.20	$165.38	($61.15)	($125.41)	($2.58)	$0.00	$2.33

C & I Medium:

							Difference due to:						
(18)		Nov-Feb ONLY	Proposed	Current									
(19)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)													
(22)		3,462	$4,131.03	$3,681.75	$449.28	12.2%	$303.98	$605.85	($155.45)	($308.12)	($10.46)	$0.00	$13.48
(23)		3,834	$4,537.00	$4,046.04	$490.96	12.1%	$330.21	$670.96	($172.15)	($341.23)	($11.56)	$0.00	$14.73
(24)		4,206	$4,942.70	$4,410.16	$532.54	12.1%	$356.41	$736.04	($188.84)	($374.34)	($12.70)	$0.00	$15.98
(25)		4,580	$5,350.71	$4,776.32	$574.39	12.0%	$382.76	$801.50	($205.65)	($407.62)	($13.83)	$0.00	$17.23
(26)		4,952	$5,756.67	$5,140.60	$616.07	12.0%	$408.99	$866.60	($222.33)	($440.72)	($14.95)	$0.00	$18.48
(27)	**Average Customer**	**5,325**	**$6,163.63**	**$5,505.85**	**$657.78**	**11.9%**	$435.27	$931.88	($239.10)	($473.93)	($16.08)	$0.00	$19.73
(28)		5,698	$6,570.60	$5,871.08	$699.52	11.9%	$461.56	$997.15	($255.84)	($507.13)	($17.21)	$0.00	$20.99
(29)		6,071	$6,977.57	$6,236.29	$741.28	11.9%	$487.85	$1,062.42	($272.59)	($540.32)	($18.32)	$0.00	$22.24
(30)		6,444	$7,384.54	$6,601.52	$783.02	11.9%	$514.14	$1,127.70	($289.35)	($573.52)	($19.44)	$0.00	$23.49
(31)		6,816	$7,790.27	$6,965.65	$824.62	11.8%	$540.34	$1,192.80	($306.05)	($606.63)	($20.58)	$0.00	$24.74
(32)		7,189	$8,197.23	$7,330.86	$866.37	11.8%	$566.63	$1,258.06	($322.78)	($639.82)	($21.71)	$0.00	$25.99

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Large:

							Difference due to:						
(1)		Nov-Feb ONLY	Proposed	Current									
(2)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		21,609	$24,637.45	$21,354.71	$3,282.74	15.4%	$1,804.44	$3,781.58	($507.81)	($1,828.13)	($65.82)	$0.00	$98.48
(8)		23,936	$27,201.26	$23,576.13	$3,625.13	15.4%	$1,987.96	$4,188.79	($562.50)	($2,024.99)	($72.89)	$0.00	$108.75
(9)		26,263	$29,765.32	$25,797.74	$3,967.58	15.4%	$2,171.52	$4,596.03	($617.17)	($2,221.85)	($79.98)	$0.00	$119.03
(10)		28,590	$32,329.34	$28,019.36	$4,309.98	15.4%	$2,355.08	$5,003.25	($671.86)	($2,418.71)	($87.07)	$0.00	$129.30
(11)		30,916	$34,892.10	$30,239.90	$4,652.21	15.4%	$2,538.53	$5,410.29	($726.54)	($2,615.49)	($94.15)	$0.00	$139.57
(12)	**Average Customer**	**33,244**	**$37,457.18**	**$32,462.39**	**$4,994.79**	**15.4%**	$2,722.16	$5,817.70	($781.23)	($2,812.44)	($101.24)	$0.00	$149.84
(13)		35,572	$40,022.23	$34,684.92	$5,337.31	15.4%	$2,905.78	$6,225.09	($835.94)	($3,009.40)	($108.34)	$0.00	$160.12
(14)		37,898	$42,584.99	$36,905.44	$5,679.56	15.4%	$3,089.24	$6,632.14	($890.61)	($3,206.17)	($115.43)	$0.00	$170.39
(15)		40,225	$45,149.03	$39,127.06	$6,021.97	15.4%	$3,272.80	$7,039.36	($945.29)	($3,403.04)	($122.51)	$0.00	$180.66
(16)		42,552	$47,713.07	$41,348.66	$6,364.41	15.4%	$3,456.35	$7,446.60	($999.98)	($3,599.90)	($129.59)	$0.00	$190.93
(17)		44,879	$50,276.89	$43,570.08	$6,706.81	15.4%	$3,639.88	$7,853.84	($1,054.65)	($3,796.77)	($136.69)	$0.00	$201.20

C & I HLF Large:

							Difference due to:						
(18)		Nov-Feb ONLY	Proposed	Current									
(19)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)													
(22)		16,001	$15,781.67	$14,151.94	$1,629.74	11.5%	$1,225.35	$1,985.72	($283.21)	($1,292.88)	($54.13)	$0.00	$48.89
(23)		17,723	$17,391.00	$15,596.94	$1,794.06	11.5%	$1,346.46	$2,199.42	($313.69)	($1,432.01)	($59.94)	$0.00	$53.82
(24)		19,446	$19,001.18	$17,042.72	$1,958.46	11.5%	$1,467.63	$2,413.25	($344.18)	($1,571.23)	($65.77)	$0.00	$58.75
(25)		21,170	$20,612.21	$18,489.31	$2,122.90	11.5%	$1,588.87	$2,627.19	($374.71)	($1,710.53)	($71.61)	$0.00	$63.69
(26)		22,893	$22,222.40	$19,935.08	$2,287.31	11.5%	$1,710.04	$2,841.02	($405.19)	($1,849.74)	($77.44)	$0.00	$68.62
(27)	**Average Customer**	**24,616**	**$23,832.58**	**$21,380.91**	**$2,451.67**	**11.5%**	$1,831.22	$3,054.84	($435.70)	($1,988.97)	($83.27)	$0.00	$73.55
(28)		26,339	$25,442.76	$22,826.70	$2,616.05	11.5%	$1,952.39	$3,268.67	($466.20)	($2,128.19)	($89.10)	$0.00	$78.48
(29)		28,062	$27,052.93	$24,272.49	$2,780.44	11.5%	$2,073.57	$3,482.49	($496.71)	($2,267.40)	($94.92)	$0.00	$83.41
(30)		29,786	$28,663.98	$25,719.04	$2,944.94	11.5%	$2,194.80	$3,696.45	($527.20)	($2,406.70)	($100.76)	$0.00	$88.35
(31)		31,509	$30,274.15	$27,164.83	$3,109.33	11.4%	$2,315.98	$3,910.27	($557.70)	($2,545.92)	($106.58)	$0.00	$93.28
(32)		33,233	$31,885.49	$28,611.69	$3,273.80	11.4%	$2,437.25	$4,124.21	($588.22)	($2,685.22)	($112.43)	$0.00	$98.21

The Narragansett Electric Company
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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption:

C & I LLF Extra-Large:

							Difference due to:						
(1)		Nov-Feb ONLY	Proposed	Current									
(2)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(3)									Base DAC	ISR			
(4)													
(5)		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(6)													
(7)		137,029	$124,703.83	$101,362.44	$23,341.39	23.0%	$2,632.85	$23,980.07	($246.65)	($3,274.99)	($450.13)	$0.00	$700.24
(8)		151,786	$137,911.07	$112,089.33	$25,821.74	23.0%	$2,884.07	$26,562.54	($273.23)	($3,627.69)	($498.61)	$0.00	$774.65
(9)		166,542	$151,117.49	$122,815.49	$28,302.00	23.0%	$3,135.29	$29,144.85	($299.77)	($3,980.35)	($547.08)	$0.00	$849.06
(10)		181,300	$164,325.56	$133,543.03	$30,782.52	23.1%	$3,386.53	$31,727.49	($326.35)	($4,333.07)	($595.55)	$0.00	$923.48
(11)		196,056	$177,531.95	$144,269.21	$33,262.74	23.1%	$3,637.75	$34,309.79	($352.90)	($4,685.74)	($644.04)	$0.00	$997.88
(12)	**Average Customer**	**210,813**	**$190,739.21**	**$154,996.06**	**$35,743.15**	**23.1%**	$3,888.97	$36,892.27	($379.47)	($5,038.42)	($692.50)	$0.00	$1,072.29
(13)		225,570	$203,946.44	$165,722.90	$38,223.54	23.1%	$4,140.20	$39,474.76	($406.02)	($5,391.12)	($740.99)	$0.00	$1,146.71
(14)		240,326	$217,152.85	$176,449.12	$40,703.73	23.1%	$4,391.42	$42,057.04	($432.60)	($5,743.79)	($789.45)	$0.00	$1,221.11
(15)		255,084	$230,360.93	$187,176.63	$43,184.30	23.1%	$4,642.66	$44,639.71	($459.15)	($6,096.51)	($837.93)	$0.00	$1,295.53
(16)		269,840	$243,567.34	$197,902.85	$45,664.50	23.1%	$4,893.87	$47,221.99	($485.71)	($6,449.18)	($886.41)	$0.00	$1,369.93
(17)		284,597	$256,774.57	$208,629.70	$48,144.88	23.1%	$5,145.10	$49,804.48	($512.27)	($6,801.88)	($934.90)	$0.00	$1,444.35

C & I HLF Extra-Large:

							Difference due to:						
(18)		Pro rate Annual	Proposed	Current									
(19)		Consumption (Therms)	Rates	Rates	Difference	% Chg	Base Rates	GCR	DAC		EE	LIHEAP	GET
(20)									Base DAC	ISR			
(21)													
(22)		173,535	$141,988.27	$120,412.04	$21,576.23	17.9%	$3,759.72	$21,535.69	$34.70	($3,765.71)	($635.46)	$0.00	$647.29
(23)		192,222	$157,056.03	$133,189.63	$23,866.40	17.9%	$4,132.30	$23,854.75	$38.46	($4,171.22)	($703.88)	$0.00	$715.99
(24)		210,911	$172,124.96	$145,968.23	$26,156.73	17.9%	$4,504.87	$26,174.05	$42.19	($4,576.78)	($772.31)	$0.00	$784.70
(25)		229,600	$187,194.14	$158,747.04	$28,447.10	17.9%	$4,877.48	$28,493.36	$45.92	($4,982.32)	($840.75)	$0.00	$853.41
(26)		248,287	$202,261.60	$171,524.40	$30,737.21	17.9%	$5,250.03	$30,812.41	$49.65	($5,387.82)	($909.18)	$0.00	$922.12
(27)	**Average Customer**	**266,976**	**$217,330.81**	**$184,303.22**	**$33,027.59**	**17.9%**	$5,622.64	$33,131.73	$53.39	($5,793.38)	($977.61)	$0.00	$990.83
(28)		285,665	$232,400.00	$197,082.07	$35,317.93	17.9%	$5,995.24	$35,451.02	$57.12	($6,198.93)	($1,046.06)	$0.00	$1,059.54
(29)		304,352	$247,467.46	$209,859.42	$37,608.04	17.9%	$6,367.79	$37,770.08	$60.85	($6,604.44)	($1,114.48)	$0.00	$1,128.24
(30)		323,041	$262,536.68	$222,638.22	$39,898.46	17.9%	$6,740.40	$40,089.38	$64.63	($7,009.98)	($1,182.92)	$0.00	$1,196.95
(31)		341,730	$277,605.59	$235,416.78	$42,188.81	17.9%	$7,112.97	$42,408.70	$68.36	($7,415.54)	($1,251.34)	$0.00	$1,265.66
(32)		360,417	$292,673.33	$248,194.41	$44,478.93	17.9%	$7,485.55	$44,727.74	$72.09	($7,821.05)	($1,319.77)	$0.00	$1,334.37

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4872
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Division 2-14

Request:

Re: the Direct Testimony of Witness Protano. Please:

a. Explain and justify the large reduction in NGPMP revenue that the Company foresees for its 2018-2019 GCR period;

b. Identify the determinants of NGPMP revenue that are:

   i. Beyond the direct influence or control of National Grid,
   ii. Within the direct influence and control of National Grid;

c. Provide the workpapers, analyses and assumptions relied upon to estimate NGPMP revenue and credits to ratepayers for the Company's 2018-2019 GCR period;

d. Explain why the Company's contracting for additional pipeline capacity through the Millennium Project does not result in opportunities expanded NGPMP revenue for the Company's 2018-19 GCR year under normal weather conditions.

Response:

a. The reduction in the Company's forecasted year-over-year Natural Gas Portfolio Management Plan (NGPMP) earnings is most directly related to current and anticipated unfavorable spot prices and forward prices leading to fewer opportunities to displace, inject, or withdraw over the period. Additionally, anticipated pipeline maintenance and a colder winter and shoulder-month period (both similar to the previous year) are expected to lead to less available capacity, because more capacity will be needed to serve firm customers, resulting in fewer opportunities to optimize.

b. The current and anticipated unfavorable relationship between spot and forward prices, as well as the expected reduction in available capacity beyond firm customer need, due to anticipated pipeline maintenance and a potentially colder than normal winter and shoulder-month period, is beyond the direct influence or control of the Company; however, the Company will continually determine if an opportunity exists to use the idle injection, withdrawal, or storage capacity to lock in margins. Additionally, the Company will optimize refill volumes for gas injected into inventory during the seven summer months (April through October) in volumes equal to the capacity of the individual storage field less the paper storage balance as of April 1 of each year. National Grid is in direct influence and control of continuously reviewing optimization opportunities in the

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marketplace by monitoring the arbitrage opportunities for transportation, storage, and supply and having the maximum number of counterparties available to execute when the market prices permit locking in favorable margins.

c. The Company's 2018-19 NGPMP revenue and credit projections included in this docket are based upon last year's results set forth in the NGPMP Annual Report for the period April 2017 through March 2018, provided as Attachment JMP-4.

d. The additional capacity through the Millennium Eastern System Upgrade Project may result in additional NGPMP revenue during the summer of 2019. However, due to the uncertainty of the price and available volumes, the Company determined not to forecast such additional NGPMP credits for inclusion in the proposed Gas Cost Recovery (GCR) factor effective November 1, 2018. If the actual NGPMP credits are greater than the amount reflected in the 2018-19 GCR factor, then the Company has the option to submit an interim GCR filing to lower the GCR factor in accordance with the Company's GCR Clause in its tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The Company would prefer to lower the GCR factor instead of needing to increase the GCR factor during the middle of a year, which could occur if the projected NGPMP credits are overstated.

Prepared by or under the supervision of: John M. Protano

Division 2-15

Request:

Re: the Direct Testimony of Witness Protano. Please:

a. Provide the Company's assessment of the cost-effectiveness of its 2017-18 Market Area Hedges;

b. Provide the Company's recommendations for Market Area Hedges for the winter of 2018-19 along with the Company's rationale for its plan for the coming winter.

Response:

a. The Company's 2017-18 Market Area Hedge program resulted in $4,159,272 in net savings to customers as compared to the cost of supply if hedges were not executed and gas supplies were purchased at market prices. Specifically, the Texas Eastern Transmission Corp. (Tetco) market area M3 (M3) basis hedges resulted in incremental savings to customers of $3,307,520 for the hedged period of January, February, and March 2018. The Company hedged the Algonquin Gas Transmission Co. (Algonquin) receipts at Ramapo, New York using Tetco M3 basis. The Transcontinental Gas Pipeline Corp. (Transco) market area Non-NY Zone 6 basis hedge resulted in an incremental savings to customers of $851,752 for January, February, and March 2018.

b. For the 2018-19 winter season, the Company's recommendation is to not use financial market area hedges for the following reasons. First, the Company's portfolio includes additional physical transactions compared to prior years, which limits the Company's exposure and transfers much of the pricing risk to less volatile, production area-based pricing. Second, an additional baseload financial hedge may lock in higher costs and limit opportunities to buy at lower cost supplies. Third, based on the current forecasts and the additional physical transactions for this upcoming winter season (November 2018 through March 2019), the estimated maximum unhedged exposure to market area prices is not expected to exceed $13 million[1], or 12 percent above all gas costs of approximately $110 million. Last year, the market area hedge proposal calculated the maximum unhedged risk at $20 million, or 25 percent above all gas costs of approximately $76 million; however, last winter did not have the benefit of the physical transactions to alleviate much of the market area pricing risk.

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[1] This estimate is based on the monthly design forecast of the Tetco M3 market area and the 95th percentile price of the Tetco M3 gas location, which attempts to capture all but 5 percent of the extreme price scenarios. Please note that under extreme scenarios, if the actual forecast verifies greater than the design forecast, or if market area prices exceed the current 95th percentile estimate, then the current estimated maximum exposure of $13 million may be exceeded.

Prepared by or under the supervision of: John M. Protano

Redacted

Division 2-16

Request:

Please detail all measures the Company has taken to better control its winter gas supply costs for the winter of 2018-19 when compared to its experience for the winter of 2017-18.

Response:

Two pipeline projects are expected to be in-service this winter in order to serve customer requirements: the Millennium Eastern System Upgrade Project (Eastern System Upgrade) and the Portland Natural Gas Transmission System (Portland) Xpress Project. As indicated in the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2017/18 to 2026/27, both of these projects provide access to more liquid supply points. The Eastern System Upgrade will displace volumes otherwise purchased at the Texas Eastern Transmission Corp. (Tetco) market area M3 (M3) index, while the Portland Xpress Project will displace volumes otherwise purchased at the Dracut, Massachusetts and/or Tennessee Gas Pipeline zone 6 index. During periods of high demand, both the Tetco M3 and Dracut/Tennessee zone 6 indices are far more volatile than Millennium Pipeline Company LLC receipts or Dawn, Ontario indices that will be accessed by these new projects.

Furthermore, the forecasted design day for winter 2018-19 has increased 9 percent and the forecasted design heating season has increased 11 percent when compared to winter 2017-18. As a result of this increase in the demand forecast, the Company needed to procure additional resources to meet the increase in customer requirements. Although the Company did not structure its requests for proposals in such a manner, the majority of physical supplies for this winter reflect [redacted]

[redacted]

Prepared by or under the supervision of:
Nancy G. Culliford, John M. Protano, and Elizabeth D. Arangio

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Division 2-17

Request:

Please detail any and all consideration National Grid has given to greater use of demand-side options to limit it exposure to increased winter gas supply costs under adverse weather conditions, including but not limited to:

a. Expansion of its interruptible (non-firm) service offerings;

b. Offering natural gas Demand-Side Management options for firm C&I Sales and/or Firm C&I Transportation service customers;

c. Offering natural gas Demand-Side Management options for Residential Heating customers;

d. If no natural gas Demand-Side Management options have been investigated by the Company to date, explain why.

Response:

a. The Company does not include load for interruptible (non-firm) service in its design day planning. These customers are expected to be off line on the design day. It is under the control of the Company to ensure reliability.

   Encouraging customers to move to a non-firm rate and curtailing their gas usage on cold days will not have significant impact on reducing gas supply costs. First, only customers with dual fuel capability can convert to non-firm service because of the tariff requirement that non-firm customers have an alternate fuel supply. Based on this requirement, the Company performed a review and analysis to determine an estimate of the maximum potential reduction in gas cost purchases if all of its firm sales dual fuel customers were on non-firm service, thereby subjecting them to curtailments called by the Company.

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The Company believes that there are currently less than 30 firm customers[1] with dual fuel capability, and only 11 of these dual fuel customers are firm sales customers that receive their gas supply from the Company. These 11 customers are those that could become non-firm transportation customers. These 11 customers account for less than 0.6 percent of the Company's annual gas purchases. To estimate the maximum potential savings the Company could realize if the 11 customers had been subject to curtailment, the Company based its analysis on actual gas prices during January 2018.[2] The Company's analysis indicates that its January 2018 gas costs may have been reduced by $875,000[3] if the 11 dual fuel sales customers were subject to curtailment, and all of their gas usage was reduced accordingly. This equates to annual gas cost savings of 0.4 percent. Although gas cost savings associated with these 11 customers may be possible, the estimated maximum potential savings of $875,000[3] is not a significant amount that justifies the time and effort needed to encourage firm sales dual fuel customers to convert to non-firm service. Also, there are many reasons why customers prefer firm service instead of interruptible service. Because these customers have dual fuel capability and could have requested non-firm service at any time, one can conclude that they prefer the benefits associated with firm, uninterrupted service. Finally, because these 11 customers are on firm service, the Company is not aware of whether they have maintained their alternate fuel supply and associated equipment as a viable option.

b. In the National Grid 2018-2020 Energy Efficiency and System Reliability Procurement Plan in Docket No. 4684, the Company commits to promoting electric energy efficiency measures that provide savings during winter peak. The Company is currently testing a gas demand response pilot in Rhode Island to evaluate the potential for demand response to be a tool for operating the natural gas system in the most efficient, reliable, and cost-effective manner. This pilot will be offered to firm commercial and industrial (C&I) customers, both sales and transport, that have a minimum annual usage of 40,000 therms and that are not one of a few excluded uses (e.g., NGV fueling stations). This pilot is focused on reducing customer usage during a three-hour period (6AM-9AM) that is coincident with the peak usage of the gas system.

[1] The Company has not maintained a list of firm customers with dual fuel capability. Therefore, the Company used a list from its 2011-12 On-System Margin reconciliation contained in its Distribution Adjustment Charge (DAC) factor.
[2] January 2018 contained significant increases in gas prices due to increased demand resulting from colder than normal weather.
[3] Calculated as the January 2018 gas usage for the 11 dual fuel sales customers of approximately 35,000 dekatherms multiplied by a price of $25 per dekatherm.

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While demand response could impact the supply portfolio for the Company, due to a reduction of peak hour requirements, it is unclear how gas demand response could affect the peak gas day requirements. Customers will not have an obligation to reduce their daily usage under this pilot, which is focused on understanding the willingness of firm customers to shift their usage outside of the peak period, thus shaping the load curve for the system. Without a reduction in peak gas day requirements, the Company's exposure to supply market variability will likely remain.

Additionally, given that demand response is a new concept for firm gas customers, this pilot allows participants the possibility of opting out of events in an emergency. If the goal is to affect the supply contracts that the Company would need to procure to meet its requirements, this sort of potential variability would need to be understood to ensure that the risk can be managed appropriately.

The Company will use the results of this pilot, as well as the other demand response programs that it is running in its other service territories, to inform future offerings and programs.

c. The Company has been exploring the possibility of offering residential demand response as part of its Connected Solutions program. This concept provides easy access to an interested customer base and would operate similar to summer events (i.e., preheating the customer's home and then reducing the temperature during the demand response event).

In 2017, the Company tested winter receptivity to demand response with customers enrolled in the Connected Solutions program with three test events. Direct results are not available for the test; however, based on the Company's experience with summer demand response, the most likely scenario is that the heating system would have been in operation 30 to 40 minutes after the event began. Most likely, the customer did not even notice a setback because the system would continue to run every 30 minutes thereafter. The summer results indicate that the average home drifts 1.2 degrees Fahrenheit every hour when the difference between a home's indoor temperature and the outdoor temperature is 10.3 degrees.

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Heat loss in a home is linearly proportional to the difference in temperature between the indoors and outdoors. In winter, the difference between indoor and outdoor temperature is 53 degrees Fahrenheit during winter peak days. As the winter temperature difference is typically five times greater than the summer temperature difference on peak days, a three degree thermostat setback would allow the heating system to remain off for less than 40 minutes. Because the Company is not able to forecast the time of grid peak in a window smaller than three hours, the Company would not be able to control heating systems to maximize the benefit and, due to the frequency of heating systems turning on during the winter, trying to impact a large number of heating systems could instead result in them all being on during the peak time since they are cycling at approximately the same time instead of at random times. This would have a negative impact to peak curtailment.

Due to these effects, the Company has decided not to focus efforts on residential thermostats with winter demand response. There is no evident path to cost effectiveness for Residential Heating customers using Wi-Fi thermostats and a small setback temperature.

d. As explained above, the Company has investigated offering demand response programs.

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